NIPER-550
Distribution Category UC-122
September 1991

Status Report

THE EFFECT OF GEL TREATMENT ON OIL RECOVERY IN A POLYMER FLOOD

Project BE4C, FY91 Annual Research Plan, Milestone 3

by

Hong W. Gao

Work Performed for the
Department of Energy
Under Cooperative Agreement
DE-FC22-83FE60149

Jerry Casteel, Project Manager
Bartlesville Project Office
Department of Energy

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

IIT Research Institute
National Institute for Petroleum and Energy Research
Box 2128
Bartlesville, Oklahoma 74005
336-2400

TABLE OF CONTENTS

TABLES

ILLUSTRATIONS

THE EFFECT OF GEL TREATMENT ON OIL RECOVERY IN A POLYMER FLOOD

by Hong W. Gao

SUMMARY

To investigate the effect of a polymer gel treatment on oil recovery in a polymer flood, simulation runs using NIPER's permeability modification simulator were conducted for polymer flood, gel treatment and combined polymer flood and gel treatment on a quarter of a five-spot, two-layer reservoir model with k_v/k_h (ratio of the vertical permeability to the horizontal permeability) ranging from 0.1 to 0.001. The permeability in the top layer was 100 mD and that in the bottom layer was 1,000 mD.

Results showed that starting a polymer flood early resulted in an early increase in incremental oil recovery regardless of the degree of crossflow. Under simulated conditions, total oil recovery at the end of 15 years of flooding was not much affected by the initiation time (between 0 and 5 yr after waterflooding was initiated) of a polymer flood.

In the simulation of combined polymer flood and gel treatment, polymer flood was (1) either initiated at the beginning of a waterflood followed by a water spacer and then a gel treatment, or (2) initiated after a gel treatment with or without a water spacer. Both near-wellbore gel treatment and deep gel placement were considered. Results showed that combined near-wellbore gel treatment and polymer flood was effective in increasing incremental oil recovery over that of a polymer flood in a reservoir having a low degree of crossflow ($k_v/k_h = 0.001$) but not in a reservoir with high crossflow ($k_v/k_h = 0.1$).

In the reservoir with $k_v/k_h = 0.001$, a near-wellbore gel treatment followed by a polymer flood was more effective in increasing incremental oil recovery over that of a polymer flood than was a deep gel placement or combined deep gel placement and polymer flood. In the reservoir with $k_v/k_h = 0.1$, a deep gel placement or combined deep gel placement and polymer flood was not effective in increasing incremental oil recovery over that of a polymer flood. Therefore, gel treatment is not recommended in a waterflood or a polymer flood in reservoirs with high crossflow.

Under simulated conditions, undesired permeability reduction in the low-permeability layer occurred in reservoirs with high and low crossflow when a large slug size of a gel system was used. The degree of permeability reduction in the low-permeability layer increased with the increase in the slug size of the polymer gel and the increase in k_v/k_h.

INTRODUCTION

This report presents the results to date from our investigation of the effect of a gel treatment on oil recovery in a polymer flood. This technology has been used in the North Stanley polymer demonstration project to prevent early breakthrough of polymer, therefore, increasing sweep efficiency and oil recovery.[1-3] However, to what extent the channelblock treatment contributed to the improvement in oil recovery over that of a polymer flood was not clear. It is the purpose of this study to investigate how a gel treatment affects oil recovery in a polymer flood in reservoirs of different degrees of crossflow using a three-dimensional, three-phase permeability modification simulator.[4-5] Results from this simulation study should be very helpful in the design of future field applications of this technology.

In this work, different combinations of gel treatment and polymer flood were simulated. Polymer flood was (1) either initiated at the beginning of a waterflood followed by a water spacer and then a gel treatment, or (2) initiated after a gel treatment with or without a water spacer. Both near-wellbore gel treatment and deep gel placement were considered. Effects of gel concentration, slug size, and gelation rate constant on oil recovery were investigated. Simulated results were then compared with those of a polymer flood in reservoirs with different degrees of crossflow.

3-D SIMULATION RUNS

All three-dimensional simulation runs reported in this report were conducted on a quarter of a five-spot, two-layer reservoir model (fig. 1) having dimensions of 1,000 ft x 1,000 ft x 30 ft with one injection well and one production well located at two opposite corners using NIPER's permeability modification simulator.[4] The thickness of each layer was 15 ft. The permeability in the top layer (L 1) was 100 mD and that in the bottom layer (L 2) was 1,000 mD. Calculations were made for three different values of vertical/horizontal permeability contrast (k_v/k_h = 0.1, 0.01 and 0.001). Detailed reservoir characteristics, fluid properties, and parameters of the in situ gelation model are listed in table 1. The original oil-in-place (OOIP) was 0.8075 x 10^6 bbl.

To investigate the effect of a gel treatment on oil recovery in a polymer flood, the effect of the initiation time of a polymer flood on oil recovery was investigated first. The size of the polymer slug injected was 0.25 PV (500 days). Polymer concentration was 1,500 ppm (zero shear viscosity = 17.6 cP at 30° C), and injection rate was 535 bbl/d. Five different initiation times, 0, 0.5, 1, 3, and 5 yr after the start of waterflood, were used in simulations. These simulated results served as a basis for comparison with that of a combined gel treatment and polymer flood. In the simulation of combined polymer flood and gel treatment, polymer flood was (1) either initiated at the beginning of a waterflood followed by a water spacer and then a gel treatment, or (2) initiated after a gel treatment with or without a water spacer. In both cases, the gel treatment was always initiated after water broke through. In all cases, polymer slug and water were injected to both layers and gel slug was injected to the high-permeability layer only. In reservoirs with k_v/k_h = 0.001, 0.01 and 0.1, water broke through at about 450, 485, and 525 days, respectively, after the start of the flood when the polymer flood was initiated at the beginning of the waterflood. The polymer concentration used in the polymer slug was 1,500 ppm unless otherwise mentioned. The gel system G1 used in the near-wellbore treatment contained 3,000 ppm of polyacrylamide, 1,000 ppm of dichromate, and 1,400 ppm of thiourea, and had a gelation reaction rate constant of 0.00001 $ppm^{-1}d^{-1}$, as shown in table 2. Gel systems of different concentrations and different gelation rate constants (table 2) and different gel slug sizes were used for deep gel placement.

RESULTS AND DISCUSSION

Polymer Flood

Results (fig. 2 through 5) showed that a polymer flood initiated at the start of a waterflood gave the earliest increase in incremental oil recovery over waterflood than did those initiated after the start of a waterflood regardless of the degree of crossflow. Figures 2 through 4 show the fractional oil recovery as a function of injected pore volumes for k_v/k_h = 0.001, 0.01 and 0.1, respectively. Figure 5 shows the incremental oil recovery as a function of injected pore volumes for k_v/k_h = 0.1. Over an extended period of flood (15 years), simulated total oil recovery was not enhanced by early polymer injection regardless of the degree of crossflow as shown in each of these figures.

Combined Near-Wellbore Gel Treatment and Polymer Flood

Simulation results showed that when the gel treatment was initiated immediately after the polymer injection (500 days), the maximum slug size of the gel system G1 that could be injected without fracturing the formation was about 0.00185 PV (equivalent to 3.7 days of injection). The fracture pressure (assumed to be 1 psi/ft) for the top layer was 8008 psi and that for the bottom layer was 8023 psi. With a water spacer of 0.0025 (50 days of injection) to 0.005 PV (100 days of injection), the maximum slug size of the gel system G1 that could be injected was about 0.00245 PV (4.9 days of injection). Reducing the polymer concentration in the polymer slug from 1,500 to 900 ppm, the maximum slug size of the gel system that could be injected was 0.0021 PV (4.2 days of injection) without a water spacer or 0.0025 PV (5.0 days of injection) with a water spacer of 0.005 PV. To inject the gel system for about 5 days at 535 b/d, a water spacer had to be used. Figures 6 through 8 show the simulated results for k_v/k_h = 0.001, 0.01, and 0.1, respectively. The total amount of polymer used in the combined gel treatment and polymer flood was the same as that used in a polymer flood. As shown in figure 6, applying a gel treatment (4.8 days) after 490 days of polymer injection and 50 days of waterflood in the reservoir with k_v/k_h = 0.001 was more effective in increasing incremental oil recovery over waterflooding than was a polymer flood or gel treatment alone. As k_v/k_h increased to 0.01 and 0.1 (fig. 7 and 8), a polymer flood followed by a water spacer and a gel treatment provided no significant improvement in oil recovery over that of a polymer flood alone.

When a polymer slug was injected after a 5-day gel treatment (system G1) either with or without a water spacer between the two slugs, a polymer concentration of above 950 ppm in the polymer slug would cause the formation to fracture in the reservoir with k_v/k_h = 0.001. This limiting polymer concentration in the polymer slug increased with the increase in k_v/k_h. It was about 1,250 and 1,350 ppm in the reservoirs with k_v/k_h = 0.01 and 0.1, respectively. Figure 6 shows that in the reservoir with k_v/k_h = 0.001, a gel treatment followed by a polymer flood gave a higher incremental oil recovery over waterflooding with less polymer consumption than did a polymer flood followed by a gel treatment or a polymer flood alone. Higher incremental oil recovery could result from a combination of polymer flood and higher permeability reduction in the high-permeability layer (L 2) than that after a gel treatment only. High-permeability reduction was caused by more gel formed by the reaction between the polymer in the polymer slug that was injected after the gel treatment and the unreacted crosslinker in the formation. As k_v/k_h increased, improvement in oil recovery over that of a polymer flood decreased, as shown in figure 7 for k_v/k_h = 0.01 and figure 8 for k_v/k_h = 0.1. In figures 7 and 8, the total amount of polymer used in the combined gel treatment and polymer flood was the same as that used in the polymer flood.

Therefore, in reservoirs with low crossflow, combined near-wellbore gel treatment and polymer flood was more effective in increasing incremental oil recovery over waterflooding than was a polymer flood or a gel treatment alone. In reservoirs with high crossflow, combined near-wellbore gel treatment and polymer flood could adversely affect the performance of a polymer flood.

Effects of Gelation Rate Constant, Gel Concentration, and Slug Size on Gel Penetration and Oil Recovery

To determine how deep gel penetration affects oil recovery from a combined gel treatment and polymer flood, strategies for achieving a deep gel penetration using gel systems of different concentrations and gelation times, different slug sizes, and different injection methods were investigated. Results showed that the largest permeability reduction factor (PRF) obtained in the high-permeability layer of the reservoir with $k_v/k_h = 0.1$ was 5.3 after injecting a gel system G2 that had a gelation rate constant of 1×10^{-6} $ppm^{-1}d^{-1}$ for 10 days. This largest PRF occurred in the injection well block. Its corresponding reduced permeability was 189 mD, which was still higher than that of the low-permeability layer (100 mD). The maximum slug size of the gel system G2 that could be injected without exceeding the formation parting pressure was 0.0058 PV (or 11.6 days). Decreasing the gelation rate constant by a factor of 10 (system G3) and increasing the slug size to 0.0065 PV (130 days) resulted in a higher PRF and deeper gel penetration in the high-permeability layer. The maximum slug size of the gel system G3 that could be injected without fracturing the formation was 0.0065 PV. The resulted PRF in the high-permeability layer ranged from 1.16 in the injection well block to 22.2 at 400 ft from the injection well. However, increasing the slug size also harmed the low-permeability layer because of the crossflow of the gel system from the high-permeability layer to the low-permeability layer. Within 300 ft of the injection well, the permeability in the low-permeability layer was reduced by more than 100-fold, and between 300 to 700 ft from the injection well, the permeability was reduced by more than 10- fold. Because of a larger slug size of the gel system used, oil recovery from the latter case was higher than that from the former case after 15 years of flood, as is shown in figure 9. At the end of 15 years of flood, the latter case recovered 10.6% (0.543 vs.0.492 of OOIP) more incremental oil than the former case.

For gel system G4 with a concentration equal to 75% of that of G3 and gel system G5 with a concentration equal to 50% of that of G3, 0.1667 PV (333 days) and 0.25 PV (500 days), respectively, could be injected without fracturing the formation. Injecting 0.1667 PV of G4 or 0.25 PV of G5 resulted in a deeper gel penetration in both high- and low-permeability layers and higher oil recovery than that in the above two cases, as is shown in figure 9. The amount of polymer used in both cases was the same as that used in a 500-d polymer flood. Gel systems G4 and G5 were used to investigate the effect of a gel treatment on oil recovery in a polymer flood for reservoirs with $k_v/k_h = 0.1$ and 0.001.

Combined Deep Gel Placement and Polymer Flood

In all simulation runs of combined deep gel placement and polymer flood, the total amount of polymer used in both gel and polymer slugs was equal to that used in a 500-day polymer flood (145,320 lb). The gelation rate constant used in all cases was 1×10^{-7} $ppm^{-1}d^{-1}$. Fractional oil recoveries from combined gel treatment and polymer flood were investigated as a function of different combinations of slug sizes and concentrations of the polymer gel slug and the polymer slug that followed the gel treatment.

It was found that for $k_v/k_h = 0.001$, oil recoveries from a deep gel placement (300 ft from the injection well to the production well) and different combinations of deep gel placement and polymer flood, as is shown in figure 10, were slightly better than that of a polymer flood. As shown in the same figure, a near-wellbore gel treatment (5 days of gel treatment) followed by a polymer flood gave a much better incremental oil recovery over waterflood than those from a deep gel placement or combined deep gel placement and polymer flood. The reason for this was that a near-wellbore gel treatment followed by a polymer flood resulted in a lower degree of permeability reduction in the low-permeability layer (PRF1) and a higher degree of permeability reduction in the high-permeability layer (PRF2) than any deep gel placement either with or without a polymer flood. A high degree of permeability reduction in the high-permeability layer resulted from the interaction of polymer that followed the gel treatment with unreacted crosslinker. In the case of near-wellbore treatment followed by a polymer flood, within 900 ft from the injection wellbore no permeability reduction occurred in the low-permeability layer (L 1). In all cases of deep gel placement, permeability reduction in the low-permeability layer occurred in all grid blocks except those near the injection well block. The degree of permeability reduction in the low-permeability layer increased with the increase in the slug size of the polymer gel.

As k_v/k_h increased, incremental oil recovery over that of a polymer flood either from a deep gel placement or from a combined deep gel placement and polymer flood decreased. Figures 11 and 12 show that no incremental oil recovery over that of a polymer flood was obtained either from a deep gel placement or from a combined deep gel placement and polymer flood in the reservoir with $k_v/k_h = 0.1$ when using gel systems G4 and G5. The decrease in incremental oil recovery over that of a polymer flood with the increase in k_v/k_h was caused by an increased permeability reduction in the low-permeability layer. For example injecting G4 for 333 days to the reservoir with $k_v/k_h = 0.1$ resulted in a PRF1 of 100 in the injection well grid block, where as injecting the same amount of gel to the reservoirs with $k_v/k_h = 0.001$ only resulted in a PRF1 of 2.03 in the injection well grid block. In the reservoir with $k_v/k_h = 0.1$, a higher permeability reduction in the low-permeability layer than in the high-permeability layer occurred within 800 ft from the injection wellbore, where as in the reservoir with $k_v/k_h = 0.001$, a higher permeability reduction in the low-permeability layer than in the high-permeability layer occurred only within 300 ft from the injection wellbore. These results indicated that deep gel placement or combined deep gel placement and polymer flood was not effective in increasing incremental oil recovery over that of a polymer flood in the reservoir with high crossflow ($k_v/k_h = 0.1$). Therefore, near-wellbore gel treatment or deep gel placement is not recommended in a waterflood or a polymer flood in reservoirs with high crossflow. Under simulated conditions, undesired permeability reduction in the low-permeability layer occurred in reservoirs with high and low crossflow when a large slug size of a gel system was used. The degree of permeability reduction in the low-permeability layer increased with the increase in k_v/k_h.

CONCLUSIONS AND RECOMMENDATION

Under simulated conditions, the following conclusions can be drawn:

1. Combined near-wellbore gel treatment and polymer flood is effective in increasing incremental oil recovery over that of a polymer flood in reservoirs with low crossflow.

2. In reservoirs with high crossflow, a polymer flood is more effective in increasing incremental oil recovery over waterflood than combined near-wellbore gel treatment and polymer flood.

3. In reservoirs with low crossflow, a combined near-wellbore gel treatment and polymer flood is more effective in increasing incremental oil recovery over that of a polymer flood than either a deep gel placement or combined deep gel placement and polymer flood.

4. Deep gel placement or combined deep gel placement and polymer flood is not effective in increasing incremental oil recovery over that of a polymer flood in reservoirs with high crossflow. Near-wellbore gel treatment or deep gel placement is not recommended in a waterflood or a polymer flood in reservoirs with high crossflow.

5. Undesired permeability reduction in the low-permeability layer can occur in reservoirs with high and low crossflow when a large slug size of a polymer gel is used. The degree of permeability reduction in the low-permeability layer increases with the increase in the slug size of the polymer gel and the increase in k_v/k_h.

6. A polymer flood initiated at the start of a waterflood gives the earliest increase in incremental oil recovery over waterflood than do those initiated after the start of a waterflood regardless of the degree of crossflow.

REFERENCES

1. Johnson, J. P. and F. W. Burtch. North Stanley Polymer Demonstration Project, First Ann. Report. Energy Research and Development Administration Report No. BERC/TPR-76/3, Oct. 1976.

2. DuBois, B. M. and F. W. Burtch. North Stanley Polymer Demonstration Project, Third Ann. and Final Report. DOE Report BETC/RI-78/19, Nov. 1978.

3. Harpole, K. J., C. J. Hill, and H. B. Carroll, Jr. Evaluation of the North Stanley Polymer Demonstration Project. DOE Report DOE/BC/10033-6, February 1983.

4. Gao, H. W. and M. M. Chang. A Three-Dimensional, Three-Phase Simulator for Permeability Modification Treatments Using Gelled Polymers. DOE Report NIPER-388, March 1990. NTIS order No. DE90000227.

5. Gao, H. W., M. M. Chang, T. E. Burchfield, and M. K. Tham. Studies of the Effects of Crossflow and Initiation Time of a Polymer Gel Treatment on Oil Recovery in a Waterflood Using a Permeability Modification Simulator. Pres. at the SPE/DOE Seventh Symposium on Enhanced Oil Recovery, Tulsa, OK, Apr. 22-25, 1990. SPE/DOE paper 20216.

TABLE 1. - Reservoir and fluid properties used in 3-D, two-layer simulation runs

Porosity	0.2
Inaccessible pore volume	0.2
Rock bulk density, lb/ft^3	143.585
Oil density, lb/ft^3	53.
Water density, lb/ft^3	64.5
Length of reservoir, ft	1,000.0
Width of reservoir, ft	1,000.0
Thickness of 1st and 2nd layers, ft	15.0
Irreducible water saturation	0.25
Initial water saturation	0.25
Residual oil saturation	0.22
Injection rate, bbl/d	535.0
Production rate, bbl/d	535.0
Absolute permeability	
top layer: k_x, mD	100.0
k_y, mD	100.0
k_z, mD	0.1, 1, 10
bottom layer: k_x, mD	1,000.0
k_y, mD	1,000.0
k_z, mD	1, 10, 100
Oil viscosity, cP	3.0
Water viscosity, cP	0.8
Polymer zero-shear-rate viscosity, cP	$\mu_p = 0.8 + 3.98E\text{-}3C + 2.29E\text{-}6C^2 + 1.695E\text{-}9C^3$
$\dot{\gamma}_{\frac{1}{2}}$ sec^{-1}	$3.923E{+}8C^{-2.116}$
p	$1.471 + 1.960E\text{-}4C - 2.882E\text{-}8C^2$
Polymer slug size, PV	0.25
Gel viscosity, cP	$\mu_g = 0.8 + 4.825E\text{-}3 + 1.608E\text{-}6C^2 + 3.6E\text{-}7C^3$
Critical onset for gelation, ppm	1,000.0
Adsorption data:	
a_k,	0.0
$b_{polymer}$	4.273E-2
b_{gel}	8.547E-2
Permeability reduction data:	
1_{polym}, ppm^{-1}	0.0
1_{gel}, ppm^{-1}	1.0
Kinetic data:	
k_1, $ppm^{-1}day^{-1}$	1.0E-5 to 1.0E-7
k_2, $ppm^{-3}day^{-1}$	1.0E-5 to 1.0E-7
Dispersion coefficients for all components:	
$D_x = D_y = D_z$, ft^2/d	1.875E-3

TABLE 2. - Characteristics of gel systems used in the simulation runs

Gel system	Dichromate, ppm	Thiourea, ppm	Polymer, ppm	Gelation rate constant, $ppm^{-1}d^{-1}$
G1	1,000	1,400	3,000	1×10^{-5}
G2	1,000	1,400	3,000	1×10^{-6}
G3	1,000	1,400	3,000	1×10^{-7}
G4	750	1,050	2,250	1×10^{-7}
G5	500	700	1,500	1×10^{-7}

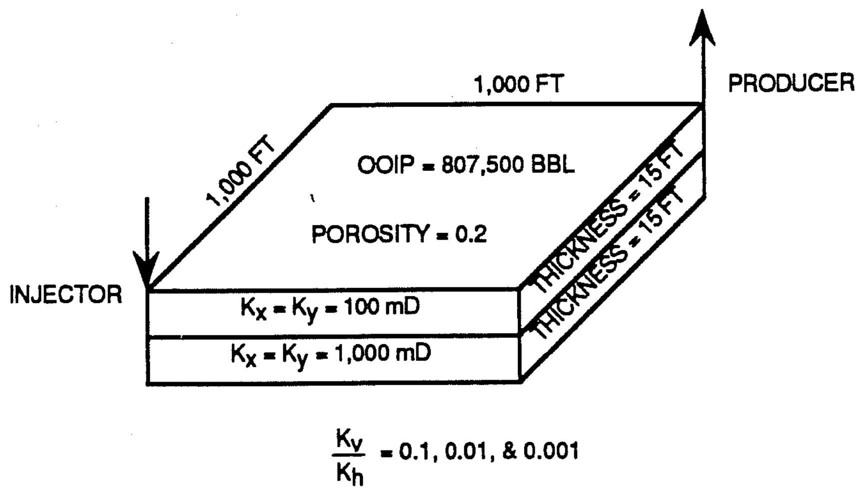

FIGURE 1. - Two-layer reservoir model.

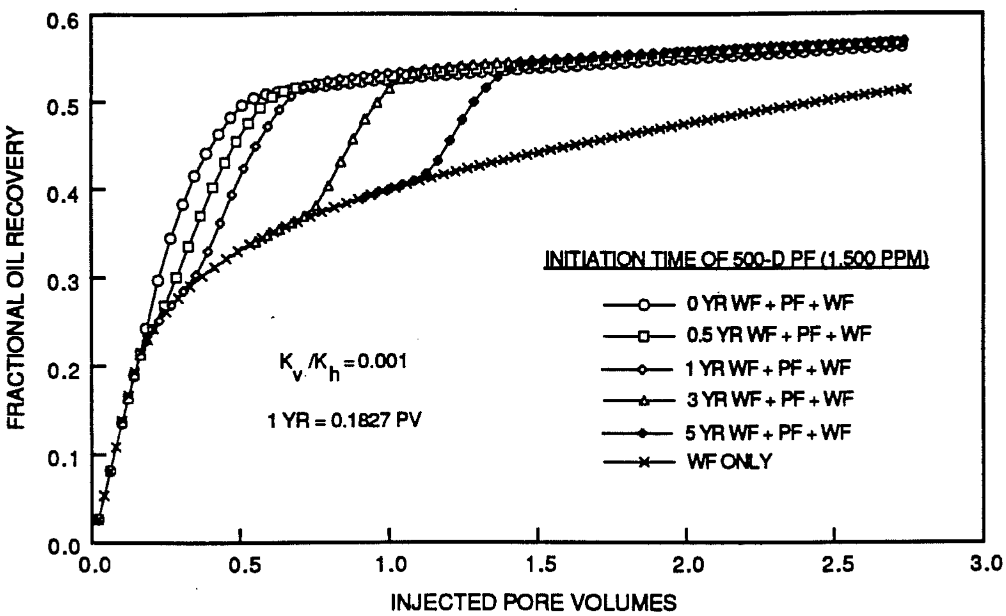

FIGURE 2. - Effect of initiation time of a 500-day polymer flood on oil recovery compared to the waterflood for $k_v/k_h = 0.001$.

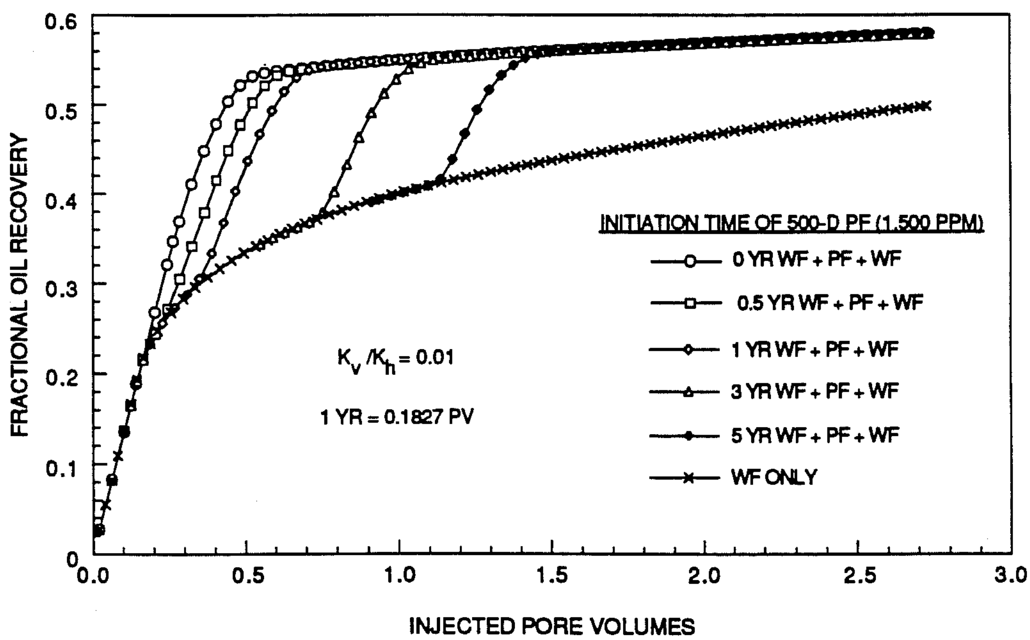

FIGURE 3. - Effect of initiation time of a 500-day polymer flood on oil recovery compared to the waterflood for $k_v/k_h = 0.01$.

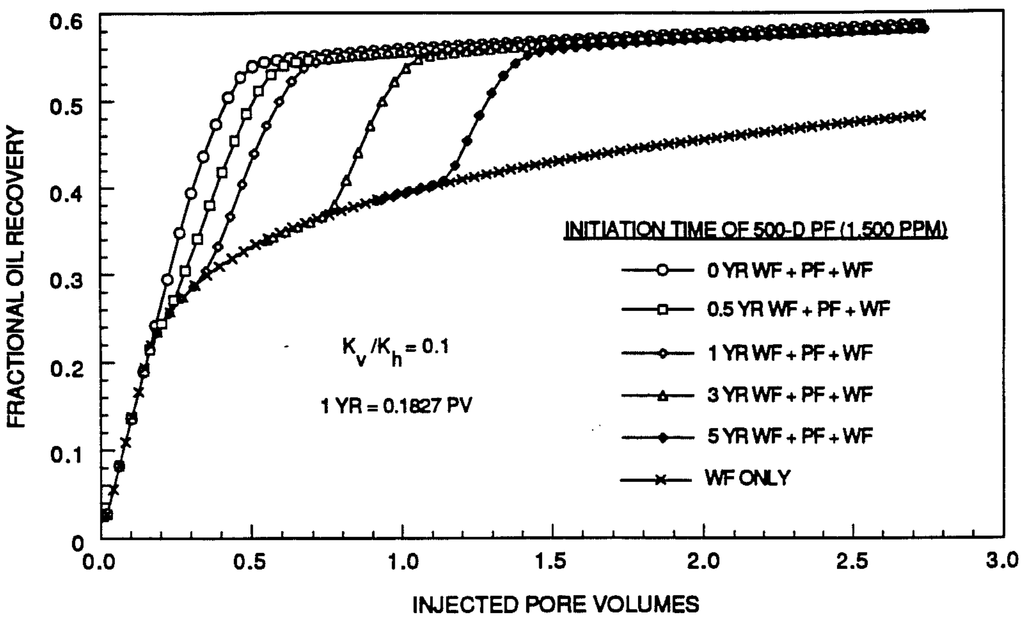

FIGURE 4. - Effect of initiation time of a 500-day polymer flood on oil recovery compared to the waterflood for $k_v/k_h = 0.1$.

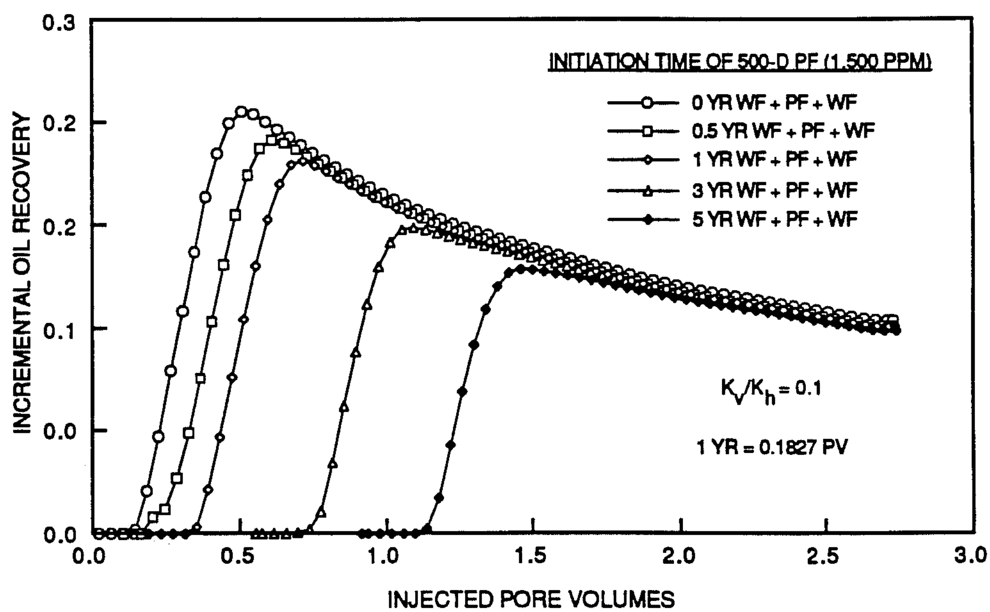

FIGURE 5. - Effect of initiation time of a 500-day polymer flood on incremental oil recovery for $k_v/k_h = 0.1$.

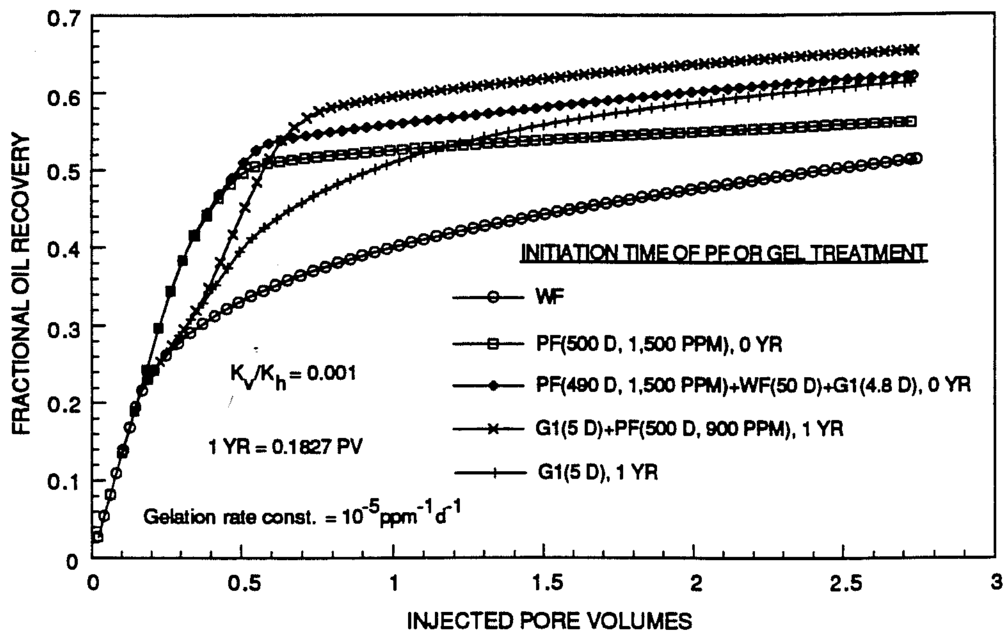

FIGURE 6. - Effect of gel treatment on oil recovery in a waterflood and a polymer flood, $k_v/k_h = 0.001$.

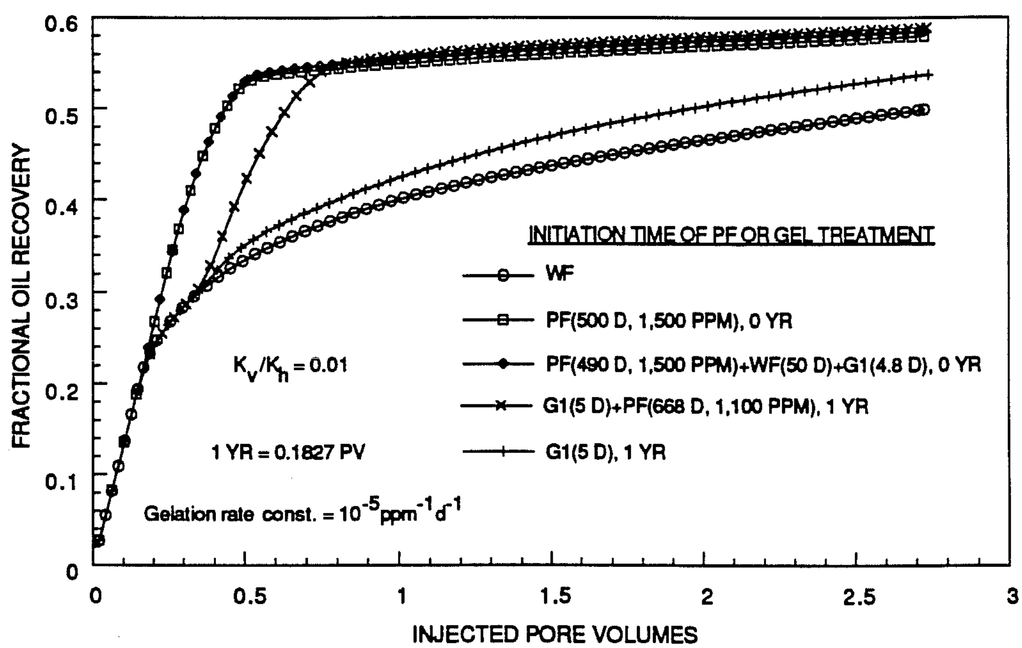

FIGURE 7. - Effect of gel treatment on oil recovery in a waterflood and a polymer flood, $k_v/k_h = 0.01$.

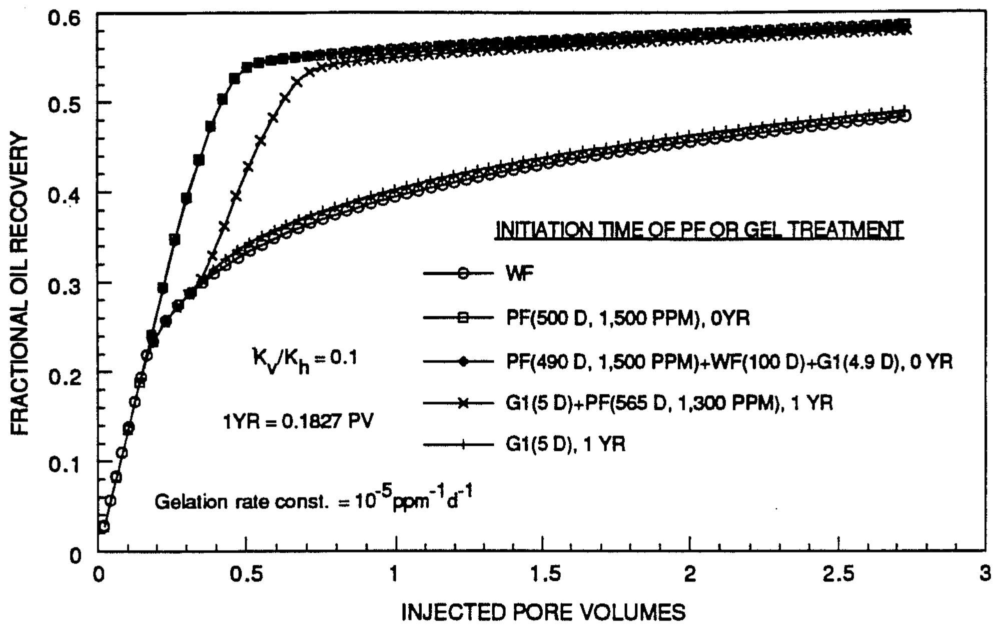

FIGURE 8. - Effect of gel treatment on oil recovery in a waterflood and a polymer flood, $k_v/k_h = 0.1$.

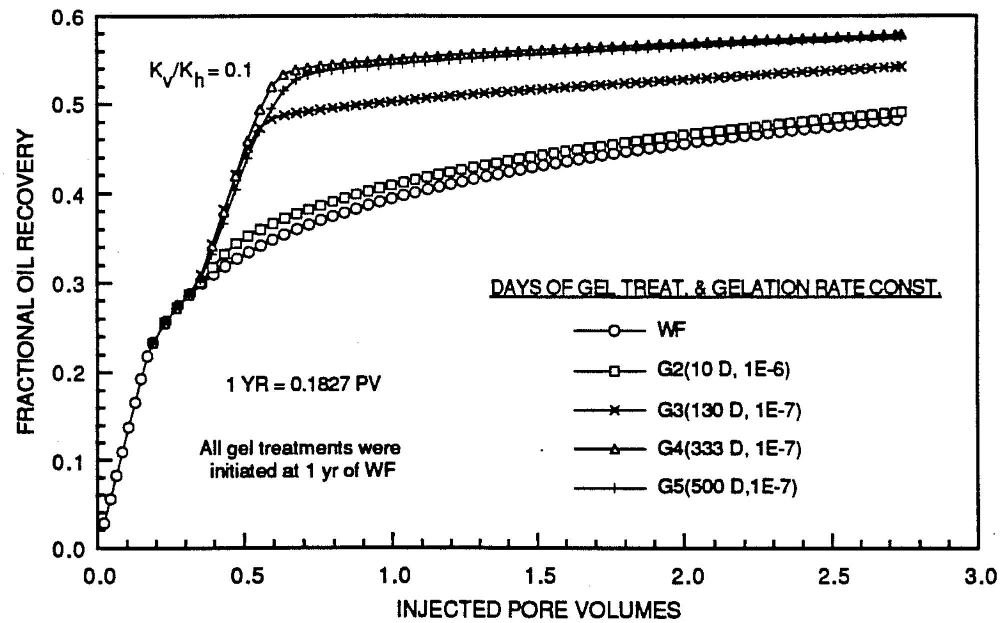

FIGURE 9. - Effects of gelation rate constant, slug size, and gel concentration on oil recovery, $k_v/k_h = 0.1$.

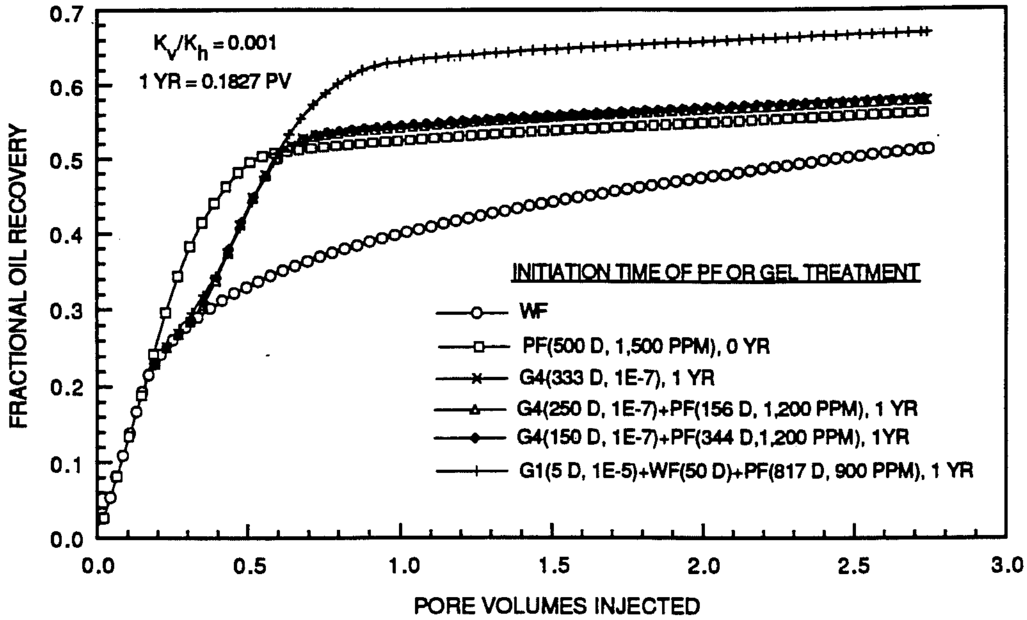

FIGURE 10. - Effect of gel treatment (gel system G4) on oil recovery in a waterflood and a polymer flood, $k_v/k_h = 0.001$.

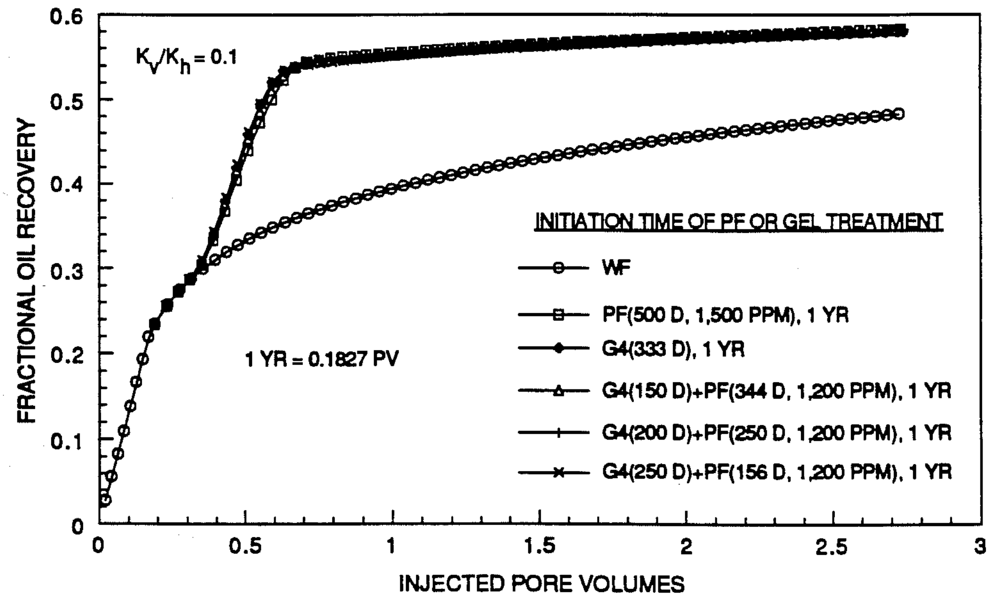

FIGURE 11. - Effect of gel treatment (gel system G4) on oil recovery in a waterflood and a polymer flood, $k_v/k_h = 0.1$.

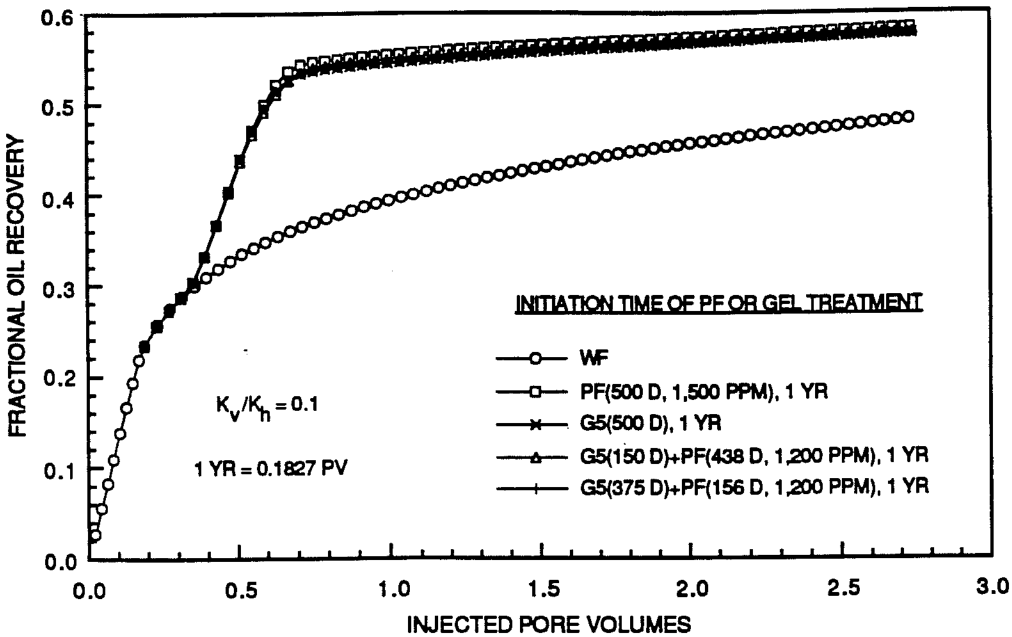

FIGURE 12. - Effect of gel treatment (gel system G5) on oil recovery in a waterflood and a polymer flood, $k_v/k_h = 0.1$.